RESERVOIR SOLUTIONS

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Ryder Scott experts to present at several venues

The top executive managers at Ryder Scott are making presentations on reserves issues during the fourth quarter at various conferences, including the Society of Petroleum Engineers annual conference in Dallas. **John Hodgin** (pictured left), president, will present a paper, "Restoring Investor Confidence through Improved Reserves Estimation and Reporting," SPE Paper No. 96807, at the SPE meeting on Tuesday, Oct. 11, at 10:55 a.m. in Ballroom C3 at the Dallas Convention Center. The paper, co-written with **Ron Harrell**, chairman at Ryder Scott, will be delivered with five other ones at the technical session, "Reserves—Do You Live In A Glass House?" that begins at 9 a.m.

Hodgin will share approaches for establishing and supervising an internal network of qualified reserves estimators with access to a secure database. He will also discuss the formation of an internal reserves audit team to ensure consistency, independence and regulatory compliance.

Hodgin will explain how to ensure that reserves verification by independent third parties is efficient.

About 10,000 attended the 2004 ATCE. Photo by Barchfeld Photography.

He will also outline several levels of third-party reserves authentication measures ranging from the design of internal processes through complete "grass roots" reserves determinations.

The presentation will cover the effects of the Sarbanes-Oxley Act on internal reserves estimation and reporting processes. "Under the new post-SOX structure, reserve reporting is moved out of the direct line of the exploration-and-production organization to the financial organization led by the chief financial

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Inside Reservoir Solutions newsletter

Shell says SEC "reasonable certainty" standard is rational

Royal Dutch Shell published new internal rules in June for booking petroleum reserves to meet U.S. regulatory guidelines, saying that "the SEC requirement of 'reasonable certainty' represents the rationally high standard of evidence/confidence consistent with the meaning of the word 'proved.'" That position is in contrast to recent criticisms from other major integrated oil companies and industry over various SEC reserves reporting issues, including the agency's

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ATCE—Cont. from Page 1

officer," said Hodgin.

Immediately following Hodgin's presentation will be one by **Dean Rietz** (pictured left), managing senior vice president at Ryder Scott, on "Reservoir Simulation and Reserves Classifications—Guidelines for Reviewing Model History Matches To Help Bridge the Gap Between Evaluators and Simulation Specialists," SPE Paper No. 96410. **Adnan Usmani**, petroleum engineer at Ryder Scott, is a co-author.

Rietz will discuss systematic reviews of models and how history matches should be evaluated in connection with reserves, assuming that the geological model is defendable. In presenting the history matching process, Rietz will discuss oil-rate-vs.-liquid-rate history matches and trial-and-error iterations. He will cite nine steps to organize a history-match review.

"The results of a model should not be used to replace good, reliable data or reasonable engineering judgement," said Rietz. "Comparisons with traditional analytical techniques, such as decline-curve analysis, provide the model with a much-needed 'reality check.'"

Also, both Hodgin and Rietz are conducting two-day short courses at the ATCE on the Oct. 8-9 weekend. Hodgin and **Bob Wagner**, senior vice president at Ryder Scott, will present a petroleum reserves course focusing on the latest developments and interpretations under definitions of the U.S. Securities and Exchange Commission and the SPE/World Petroleum Congress. They also will focus on typical errors in reserves estimates and how to avoid them. They also will discuss reservoir simulation and probabilistic methods.

Rietz and a co-instructor will present "Reservoir Simulation for Practical Decision Making." They will focus on data acquisition, fluid properties, rock-fluid interaction, grid construction, history matching and prediction cases. The course will help attendees better understand how to plan and conduct a reservoir study and how to review a study conducted by someone else. For information on these courses, go to http://www.spe.org/atce/2005.

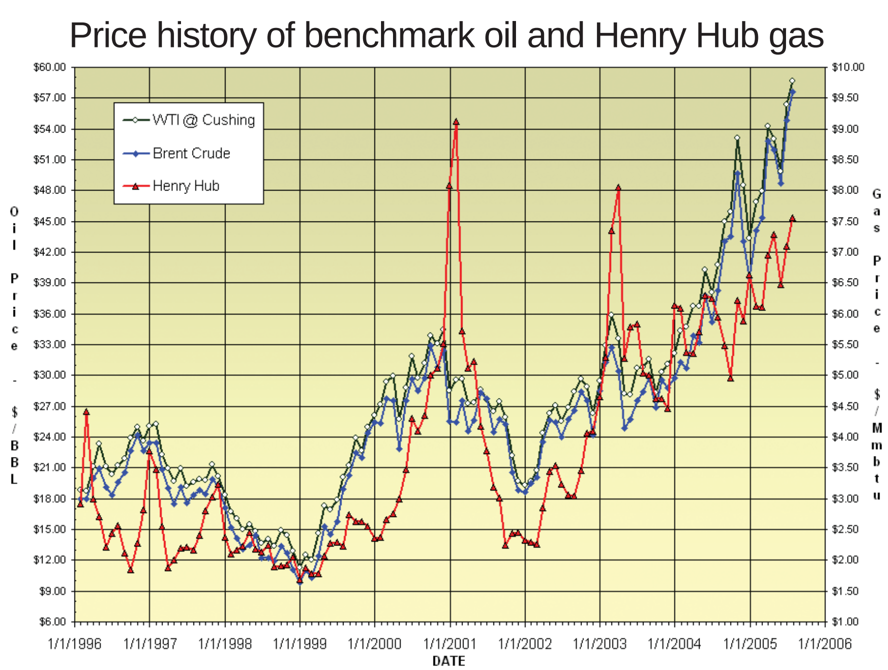
On the ATCE exhibit floor, Ryder Scott is offering *Reservoir Solutions* freeware CDs, program demos and publications at booth space 1141.

Train now, certify later

Harrell will present a paper, "Restoring Investor Confidence in Petroleum Reserves Worldwide - A Joint Effort by Industry Professionals," SPE Paper No. 10179, at the SPE International Petroleum Technology Conference in Doha, Qatar, Tuesday, Nov. 22 at 4:30 p.m. in the Salwa Ballroom II at the Sheraton Doha Conference Centre. Harrell and **Bala Dharan**, professor of accounting at Rice University, wrote the paper.

Four other presentations on reserves will be made at the special session, "Reserves: Getting it Right," which begins at 2:30 p.m. Harrell's focus will be on the training and certification of petroleum reserves evaluators. (See "The time has come to certify reserves evaluators," *Reservoir Solutions* newsletter, March 2004, Page 1.)

Harrell said that the American Association of Petroleum Geologists



The historical price chart shows published, monthly-average, cash market prices for WTI crude at Cushing (NYMEX), Brent crude and Henry Hub gas.

Publisher's Statement

Reservoir Solutions newsletter is published quarterly by Ryder Scott Company LP. Established in 1937, the reservoir evaluation consulting firm performs hundreds of studies a year. Ryder Scott multidisciplinary studies incorporate geophysics, petrophysics, geology, petroleum engineering, reservoir simulation and economics. With 100 employees, including 63 engineers and geoscientists, Ryder Scott has the capability to complete the largest, most complex reservoir-evaluation projects in a timely manner.

Reservoir Solutions

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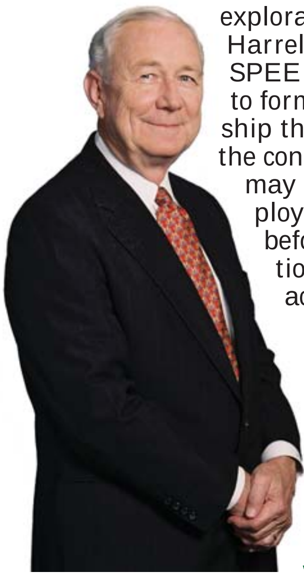
and the Society of Petroleum Evaluation Engineers, the two organizations considering funding the training and certification program, are receiving more positive responses on training than on formal, sanctioned certification.



"The certification initiative remains exploratory at this time," said Harrell (pictured left). "Neither the SPEE nor the AAPG has committed to formally adopting full sponsorship though both are committed to the concepts. The training elements may need to be developed, deployed and evaluated by industry before the concepts of examination and certification become accepted."

SPEE was scheduled to decide whether to formally support the initiative during the fourth quarter. At press time, AAPG had not decided the issue but planned to make an announcement in August.

WPC roundtable

Harrell will be one of six panelists at the 18th WPC roundtable on reserves and resources on Thursday, Sept. 29, from 1:45 to 3:45 p.m., at the Sandton Convention Centre in Johannesburg, South Africa. The roundtable will focus on the needs for accurate information in oil and gas resources management and on comparable information in financial reporting. For more information, go to www.18wpc.com.

Canadian-style SOX

At an upcoming conference, **Fred Richoux** (pictured right), executive vice president and director of Canadian operations at Ryder Scott, will analyze policies and procedures in the preparation of reserves estimates and reporting under the relatively new Canada Bill C-198 and the U.S. Sarbanes-Oxley Act. He will present "Lessons Learned from Sarbanes-Oxley" on Thursday, Oct. 6 at 11:15 a.m. at the Insight Information conference, "Effective Financial Reporting and Reserves Disclosures for the Oil and Gas Industry," at the Metropolitan Centre in Calgary.

Richoux will focus on steps to assure management and investors that reserves estimates are reliable. He will cite applicable lessons learned from Sarbanes-Oxley outside the United States, provide updates on the implementation of Bill C-198 in the oil and gas industry and outline SOX's effect on companies that are dual filers.

David C. Elliott, senior petroleum evaluation geologist at the Alberta Securities Commission, is a co-chairman.

Bill C-198 is intended to ensure that Canadian companies comply with the various requirements of regulatory authorities for the disclosure and preparation of financial and non-financial information. C-198 provides regulatory authorities with the following enforcement tools:

- New rule-making power to require CEOs and CFOs to certify the adequacy of internal controls
- New rule-making power over the composition and responsibilities of audit committees
- Civil liability for continuous disclosure
- New prohibitions against securities fraud, market manipulation and making a misleading or untrue statement
- New regulatory sanctions and criminal penalties

For more information on the conference, go to www.insightinfo.com.

E&Y conference for O&G execs

Don Roesle (pictured right), CEO at Ryder Scott, will present the latest issues in petroleum reserves disclosures at the annual Ernst & Young Thought Leadership Conference for energy executives, Explorations 2005, Tuesday, Oct. 11, in Houston. He will discuss management measures taken by oil and gas companies to assure unbiased reserves reporting.

This includes the establishment of internal controls, proper training of technical staff, organization of data and backup documentation and addressing problem areas. He will also discuss reserves categories, including proved, and the inherent uncertainty in estimates that are factored into performance metrics used by investment analysts.

The full-day event will begin at 8 a.m. at the Westin Galleria Hotel, 5060 West Alabama St. in Houston. For more information, go to www.ey.com.

Roesle to conduct IQPC workshop

Roesle also will conduct an IQPC master class on "Sarbanes-Oxley: Reserves Reporting & Compliance" on Wednesday, Sept. 14, from 1:30 to 5:30 p.m., at the Thistle Marble Arch hotel in London. He will investigate the roles of the independent reserves auditor and management and their commitment to transparent and competent estimation and reporting of proved reserves. This is a post-conference workshop. Ryder Scott is a featured exhibitor at the event on Sept. 12 and 13, also at Thistle Marble Arch.

This will not be the only Ryder Scott-led workshop during September. Hodgin will present a four-hour workshop on reserve definitions and reporting requirements on Tuesday, Sept. 20 in Dallas.

Please see details on Page 8.

Technical challenges in estimating reserves Part 4: Production decline curves, operating costs

Editor's Note: This is a revised excerpt from "Oil and Gas Reserves Estimates: Recurring Mistakes and Errors," (SPE Paper No. 91069). To order a copy of the full paper, go to www.spe.org and access the e-library.

Ryder Scott personnel see a wide variety of internally produced petroleum reserves estimates and most of them are well prepared. However, the firm has noticed common technical errors in reserves estimates.

This multipart article offers guidelines to help reduce the chance of errors in geoscientific and engineering analysis. This fourth newsletter article focuses on decline-curve analysis and operating costs.

Production decline curves

Performance decline analysis is the most common technique to estimate reserves in mature fields where ample performance data is available for both primary and secondary products. Besides the obvious subjectivity in determining a decline trend, common errors are associated with composite field decline curves and neglecting to apply a minimum hyperbolic decline rate.

Composite field production decline curves—Quite often, an engineer only has production histories for a multi-well lease, production unit, single reservoir or entire field. Individual well-production histories may not be available or can be compiled only through the use of allocations relying upon less-than-perfect well tests. When an aggregate well-production history is displayed as a graph of monthly oil or gas production, the historical trend may show a continual decline over time.

Indeed, this trend may be well defined as an exponential or hyperbolic decline that can be projected into the future with a reasonably high degree of reliability based upon the mathematical "best fit" of the historical data. This is illustrated as Figure 12.

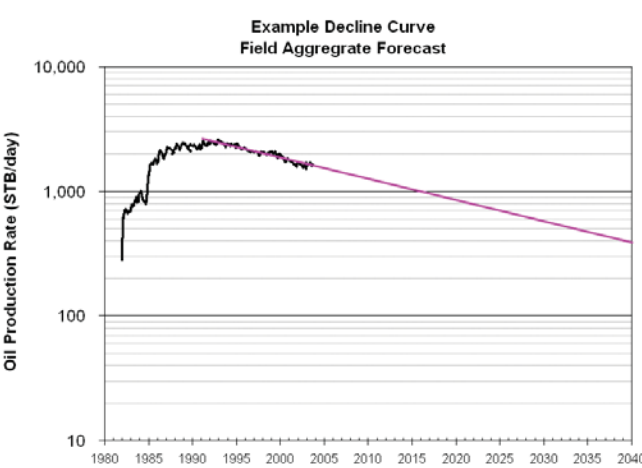


Figure 12. Field aggregate forecast based on apparent trend.

This projection clearly presents an appealing case for using the entire production history to obtain an estimate of proved reserves.

Such a decline projection may be acceptable, however, only under the following conditions:

- Well count is relatively stable.
- Production conditions and methods are largely unchanged over the producing life.
- Wellbore intervention and other remedial work can be classified solely as maintenance.

If these rather stringent conditions are not met, reliance upon this projection to estimate proved reserves may be inappropriate.

Figure 13 has the same production decline curve as Figure 12 but contains additional plotted data reflecting the number of producing wells over the productive life of the field. Often overlooked, this added information has a significant effect on the previous interpretation of remaining proved reserves.

Clearly, the forecast in Figure 12 is not achievable without the continual drilling of additional wells achieving similar, positive results, a highly unlikely condition in most cases. Frequently, estimators use this erroneous approach to estimate proved producing reserves.

In some cases, evaluators compound their mistakes by adding yet even more proved undeveloped reserves assigned to discrete drilling locations.

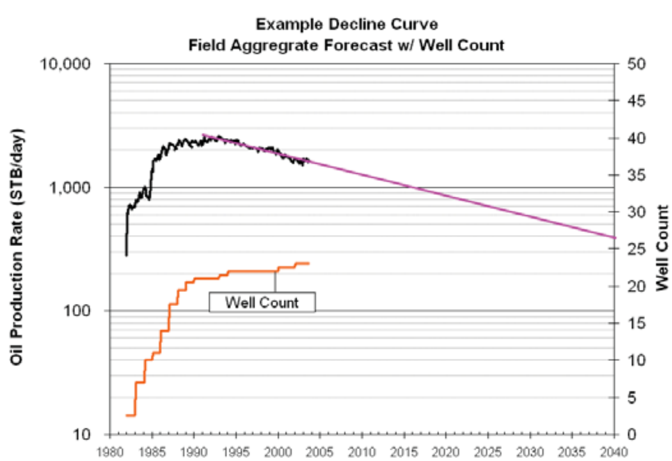


Figure 13. Field forecast based on apparent trend with well count.

In preparing a forecast such as that in Figure 14, which restates the data in figures 12 and 13 based on average monthly production per well, an evaluator should be cautious when using "average well" projections.

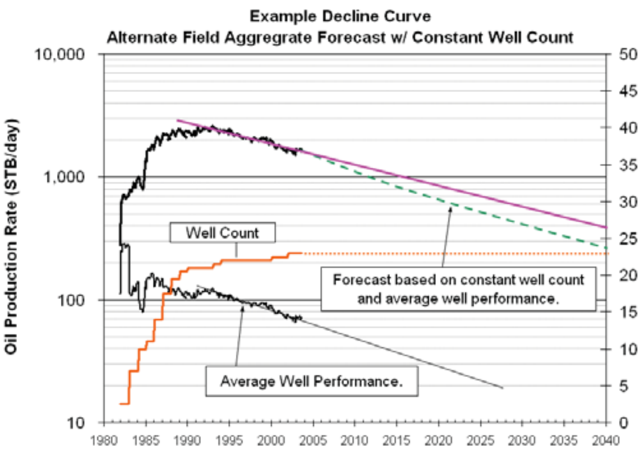


Figure 14. Alternate forecast based on constant well count and average well performance.

The average well production, which is determined by dividing the field production by the well count, may have been sustained by the continuing impact of production from new wells and well-maintenance work.

Figure 15 presents a final forecast without the effects of drilling and single-event workovers on the field trend. The final projection may yet overstate remaining reserves unless the evaluator can be assured of future opportunities for re-completions, stimulation treatments or other types of production enhancements.

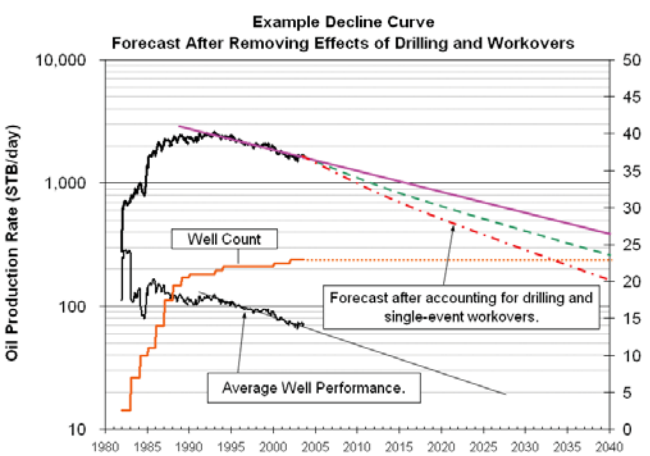


Figure 15. Alternate forecast after removing effects of drilling and single-event well-maintenance work.

The preferred approach is to rely upon the performance of individual wells whenever possible. Any other approach may lead to an optimistic estimate of future performance and proved reserves.

Failure to specify minimum decline rates in hyperbolic projections. Virtually all commercial software programs used to forecast future production rates and cash flows provide an option to use a hyperbolic projection with a specified N-factor and final decline rate. This N-factor can also be calculated by using the curve-fitting function of the economic software program.

Allowing the software to default to an unspecified, final decline rate, which is often unreasonable and unsupportable, may have little effect on present value. However, the "added" reserves frequently cause gross overestimations. A review of depleted or nearly depleted area analogs will often guide the selection of an appropriate final decline rate.

Other errors with decline-curve analysis

- Ultimate recovery not related to volumetric estimates. Apparent decline trends combined with relatively flat flowing-tubing pressures can lead to optimistic reserves estimates, particularly in gas reservoirs with partial to strong water drives.
- Assuming exponential decline in reservoirs that tend to exhibit hyperbolic decline trends (source of underestimating reserves). These include (i) tight gas reservoirs (enhanced if multiple layers), (ii) naturally fractured reservoirs, and (iii) waterflood reservoirs.
- Conversely, assuming a hyperbolic decline may lead to overstating reserves in cases where an exponential decline would also fit performance.

Guidelines to reduce mistakes in decline-curve analysis

- Always attempt to estimate performance decline at a well or completion level for best results.
- Include trends in secondary products (condensate yields, gas-oil ratios, water cuts) in analysis.
- When projecting group- or field-level rates, make sure to review the components of the field curve and properly account for well work and associated costs that are required to maintain the decline trend. If well work cannot be sustained, the field curve needs to be adjusted to fit the true decline of existing wells.
- Use analogous fields or more mature wells in the field or area to establish typical decline behavior, including minimum hyperbolic decline rates.
- Gain an understanding of reservoir properties — porosity, permeability, lithology and depositional environment — to exercise better judgment in selecting exponential vs. hyperbolic decline models.
- Attempt to combine various types of evaluation techniques with decline-curve analysis to assure consistency in results.

Operating costs

Operating costs reflect expenses attributable to the daily operations of a field and typically do not include general and administrative expenses or other overhead costs. Operating costs are used to capture expenses, which affect reserves values, and to estimate economic limits, which affect reserves volumes. The economic limit is defined as the rate and time at which revenue from production becomes less than the cost of operations.

Typical errors or mistakes associated with operating costs include the following: (i) use of forecasted or budgeted operating costs that are lower than actual

Please see Operating Costs on Page 6

Operating Costs—Cont. from Page 5

long-term historic costs, (ii) recurring well or facility costs that are assumed to be single events and therefore excluded from future estimates of cost, (iii) assumption of per unit cost of primary product, dollars per barrel for example, without the proper treatment of fixed cost or costs of producing secondary products, and (iv) failure to evaluate changes to costs caused by the introduction of new recovery mechanisms.

Projected operating costs are lower than historic average costs—Occasionally, forecasted or budgeted operating costs that are lower than average historic costs are used to estimate reserves. This may be based on an assumption rather than established fact.

This approach, in most cases, will result in overstating both income and reserves. In general, regulatory bodies require that operating costs be closely tied to at least one if not several years of observed costs. Any deviation requires sufficient evidence of circumstances and events that will lower future operating costs.

Recurring well or facility expenses—Most reservoir engineers rely on historic facility, lease, and/or well operating cost statements as the basis for calculating historic operating costs, typically expressed as a monthly cost, for mature properties. This may further be subdivided into fixed and variable components when appropriate. Historical costs frequently include expenses that are deemed to be "non-recurring."

These costs are typically excluded from average costs for use in production forecasts. This approach is acceptable only if the "non-recurring" costs are indeed non-recurring.

All too often, such items as tubing repairs and/or replacement or periodic platform or facility maintenance, are deducted as non-recurring. The failure to recognize the periodic frequency of such maintenance can lead to an overstatement of reserves and future net income.

Assumption of per-unit operating cost—Alternatively, and perhaps of a more serious nature, some evaluators use a future operating cost expressed as a fixed unit cost per volume (barrel, mcf or cubic meter) based on their estimates from a current or past analog. This method does not properly account for variable costs or proper inclusion of secondary products.

This approach is virtually never acceptable as unit costs of production almost universally increase over time with declining production even if the total monthly or annual costs remain constant or slightly decline. This increase in unit costs of production is exacerbated by increasing needs for compression and artificial lift and a continuing growth in maintenance related to corrosion, equipment repairs, water treatment and disposal and ever-expanding environmental concerns. An understatement of operating costs will lead to an overstatement of future net income and reserves.

All performance-derived estimates of reserves are limited by a terminal rate, which is typically described as an economic limit. A unit cost of oil or gas production never leads to an economic limit as the cost will simply remain a fraction of revenue, which illustrates the improper assumption of a constant unit operating cost.

Changes in recovery process—Problems in operating-cost estimates can also occur if future production involves new recovery mechanisms, for instance, the start of a waterflood. In such cases, an evaluator should conduct a careful review to properly account for changes in costs resulting from added operational requirements.

Guidelines to reduce operating-cost mistakes

- Future operating costs need to closely agree with observed historic costs. Incorporate at least two to three years of lease operating expenses into the estimate of future costs.
- Attempt to separate costs into fixed and variable components.
- Include recurring well or facility expenses in operating cost.
- Account for changes in costs caused by new recovery mechanism.
- Avoid simplification by estimating cost per unit volume without fixed/variable split.
- Include cost for handling of secondary products.
- Apply proper escalation of costs if applicable reserves definitions allow for such.

Editor's Note: Part 5 to be published in December.

Shell—Cont. from Page 1

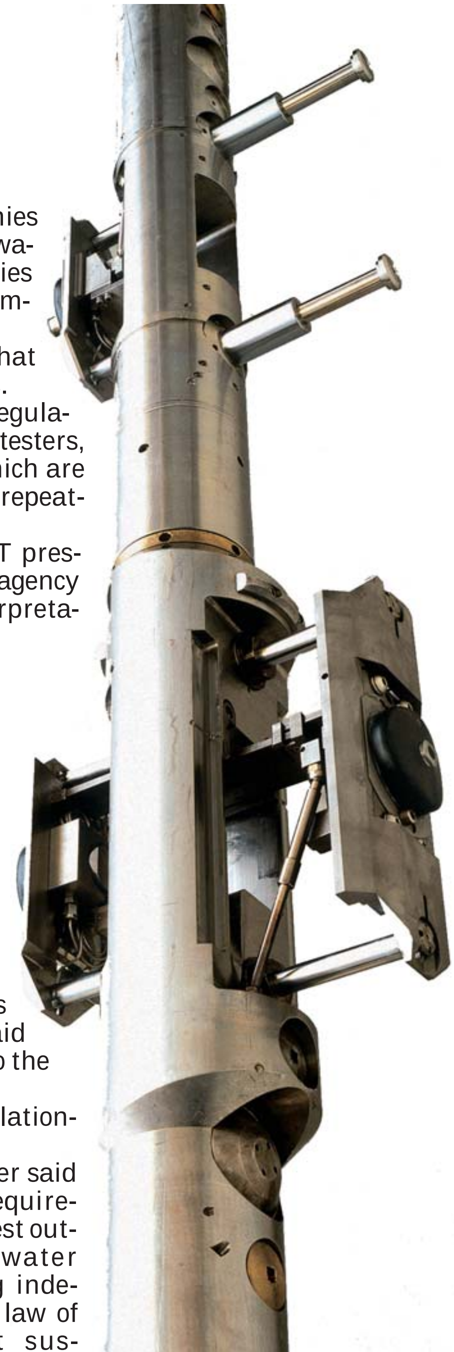
interpretation of the "reasonable certainty" guideline.

A Cambridge Energy Research Assocs. study on U.S. oil and gas reserves reporting requirements, published Feb. 22, stated that "the requirement for recognizing proved reserves has …shifted from 'reasonable certainty' toward 'absolute certainty.'" (See article on CERA report in March 2005 *Reservoir Solutions* newsletter, Page 3.) Shell was not among five IOCs and others that sponsored the CERA study, the *Oil & Gas Journal* reported.

Other IOCs have questioned a relaxation of required flow testing for the deepwater Gulf of Mexico that excludes other offshore areas. This year, they debated the requirement to use single-day pricing in filing annual reserves estimates with the SEC.

Shell's new internal policies require that it make final investment approval for fields of 50 million BOE or more before it can book its reserves as proved. In addition, for smaller fields, Shell must have evidence that similar projects have come to fruition.

Industry asks SEC to broaden its acceptance of WFT data for reserves



Wireline formation testers don't get enough respect, oil and gas companies say. WFTs define lowest known hydrocarbons in downdip oil-water and gas-water contacts at high enough certainty levels to be accepted by the U.S. Securities and Exchange Commission for estimating proved reserves, said several E&P companies at the latest Energy Forum on reserves.

However, citing abuse of the "technology case," the SEC has insisted that companies use LKHs delineated by well logs only to estimate proved reserves.

Industry personnel attending the May 24 forum recommended that U.S. regulators reconsider the use of WFTs—including MDTs (modular formation dynamics testers, a Schlumberger product)—in defining reservoir fluid contacts. The tests—which are industry-accepted technologies based on basic fluid science—produce reliable, repeatable results, attendees said.

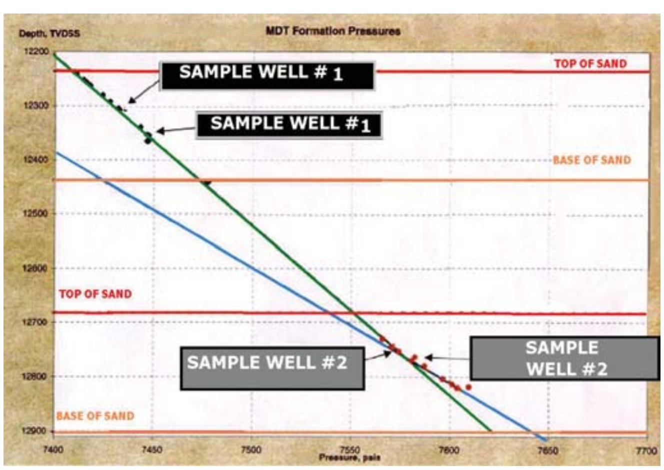
Up to 2003, the SEC had accepted valid, reliable interpretations of WFT pressure-gradient data and seismic information to define LKHs. However, the agency reverted to a stricter policy after reviewing what it considered to be misinterpretations of the WFT sampling data by some public companies.

> "Science is science. Laws of fluids and fluid relationships are the same in the GOM as in other offshore regions. ...The law of physics is not suspended at deep water."

Attendees also wanted the SEC to accept a combination of WFT data, log and core data and seismic information to estimate proved undeveloped reserves in discoveries outside the deepwater Gulf of Mexico. Last year, the SEC said that it would allow E&P companies to use that data suite in lieu of a flow test to the surface to estimate PUDs but only in the deepwater GOM.

One attendee remarked, "Science is science. Laws of fluids and fluid relationships are the same in the GOM as in other offshore regions."

At an earlier Energy Forum this year, the CEO at an independent producer said that the SEC requirement for a flow test outside the deepwater GOM is hurting independents. "The law of physics is not suspended at deep water," he said, pointing to what he believes is a double standard.



These MDT pressure measurements from two samples from each of two wells establish an oil-water contact as a basis for determining the lowest known hydrocarbons, a key parameter for estimating proved reserves under SEC regulations.

He added that the SEC interpretation forces GOM shelf operators to carry out expensive flow tests to book reserves that are used as collateral in loans and that help determine value in the equity markets. "The (flow testing) requirement makes some marginal fields uneconomic," he said.

The Energy Forum will host reserves conferences in Houston on Sept. 14, Denver on Oct. 25 and Calgary on Oct. 27. For more information, go to www.theenergyforum.com/reserves_events.asp.

Editor's Note: Photo of MDT (above) courtesy of Schlumberger.

PEs join Ryder Scott

Mark E. McCloskey (left), petroleum engineer, recently joined Ryder Scott. Previously, he was a consultant at PLS Inc. and vice president at Harrison Lovegrove LLC. McCloskey represented buy and sell sides and evaluated acquisitions and divestitures of U.S. and international oil and gas properties. He also developed exploration-and-development strategies for clients. Previously, McCloskey was director of corporate development at Venoco Inc. He performed technical and financial evaluations of petroleum interests and assessed risk in development plans starting in 2001. McCloskey also was director of business development at Vastar Resources Inc. in the late 1990s where he evaluated properties and managed A&D and a technical staff. From 1991 to 1997, he was vice president of business development and reserves at Gulf Resources Corp. He developed corporate strategies in A&D, asset development, financing and business development and supervised a technical staff. McCloskey was manager of acquisitions at Geodyne Resources from 1986 to 1991. He worked at Arco Oil & Gas Co. as a reservoir engineer from 1980 to 1986. McCloskey has a BS degree in petroleum engineering from Texas A&M.

Larry E. McHalffey (right column), petroleum engineer, joined Ryder Scott after working at the firm as a consulting engineer two years. He conducted decline-curve and material-balance analysis and volumetric interpretations in preparing reservoir and economic evaluations. Previously, he was a petroleum engineering manager at Gaither Petroleum Corp. and before that at Ginger Oil Co. starting in 1999. McHalffey evaluated development drilling prospects, analyzed divestitures and prepared economic and risk models. He also prepared reserves reports and cashflow projections and evaluated acquisitions. He was a senior petroleum engineer at King Ranch Energy in the late 1990s and at Santa Fe Energy Resources from 1995 to 1998 where he conducted engineering and economic reviews of gulf coast properties and evaluated divestitures.

From 1991 to 1995, he worked at Dalen Resources Oil & Gas Co. as a reservoir engineer and evaluated drilling projects offshore Louisiana. From 1982 to 1990, he was a production engineer, reservoir engineer and reservoir engineering manager at Corpus Christi Oil & Gas Co. McHalffey worked at Texaco Inc. as a petroleum engineer from 1978 to 1982.

He has a BS degree in petroleum engineering from Texas A&M. He is a member of the Society of Petroleum Engineers and American Petroleum Institute.

Hodgin to present in Dallas

John Hodgin, president at Ryder Scott, will present a four-hour workshop on reserve definitions and reporting requirements on Tuesday, Sept. 20 at a three-day conference at the Ellison Miles Geotechnology Institute in Dallas. The event is sponsored by the Texas Region Petroleum Technology Transfer Conference and will focus on how to avoid reserves writedowns. Hodgin will discuss similarities and differences in SEC and SPE/WPC reserve reporting guidelines, SEC red flags and how to avoid them. The courses are designed for geoscientists, petrophysicists and petroleum engineers. For information, go to www.energyconnect.com/pttc.

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